Steam ESA - Domtar Paper
Public Report – Final

Company	Domtar Paper	**ESA Dates**	CONFIDENTIAL
Plant	Rothschild	**ESA Type**	Steam
Product	Paper Products	**ESA Specialists**	Tom Tucker, P.E. Dick Reese

Table 1

ENERGY SAVINGS OPPORTUNITY SUMMARY INFORMATION					
Identified Opportunity	**Savings/yr**				
	$	**kWh**	**MMBtu**	**Fuel Type**	**N,M,L**
1. Reduce Steam Demand – Consider a Condensing Economizer on Gas Boilers	N/A	0	110,000	Natural Gas	M
2. Steam Demand Reduction – Recover Heat from Paper Mill Lift Station to Filter Plant	N/A	0	60,000	Natural gas	M
3. Increase Boiler Efficiency- Use #1 Boiler Economizer to Preheat #2 Boiler Feedwater	N/A	0	21,000	Natural gas	N/M
4. Increase Condensate Recovery Rate – Return Sewered Steam Condensate	N/A	0	10,000	Natural gas	N/M
5. Improve Boiler Efficiency – _Implement a Scheduled Seasonal Tuning Program	N/A	0	9,000	Natural gas	N
6. Improve Boiler Efficiency - Reduce the Blow Down Rate	N/A	0	6,500	Natural gas/Wood	N
7. Improve Boiler Efficiency - Pull Hot Boiler House Air from Roof as Combustion Air	N/A	0	6,000	Natural gas	N/M
8. Increase Condensate Recovery Rate – Improve Paper Machine Hotwell Management	N/A	0	4,500	Natural gas	N/M
9. Use 40# Instead of 140# Steam on Unit Heaters (this will increase BP turbine electrical output)	N/A	1,200,000	0%	Natural gas	N/M
10. Reduce Steam Venting – Hot Lime Softener	N/A	0	3,300	Natural gas	N
11. Consider a VFD on #1 Boiler ID Fan	N/A	400,000	0	Electricity	M

Brief Narrative Summary Report for the Energy Savings Assessment:

Introduction:

The ESA and training activities were provided through the United States Department of Energy-Energy Savings Now initiative, which was begun to help the largest natural gas users in the United States identify ways to reduce operating expenses by optimizing energy use. The steam system at a Domtar mill was the target of an ESA conducted in 2008. With permission from Domtar, recently qualified "Steam Experts" were also in attendance to gain experience with use of the steam tools and assessment activities.

Utilities
The mill boilers use a mix of fuel that includes natural gas and biomass (wood). Steam is raised to 600-psig and 720°F and fed to a backpressure turbine, a line shaft turbine and pressure reducing stations. Medium pressure steam at 140-psig (100-psig steam was treated as 140-psig) and low pressure 40-psig steam is used to meet process requirements through pressure reduction or direct use as appropriate.

Objective of ESA:
The primary objective of the ESA was to identify low cost and capital opportunities to reduce steam demand. Additionally, the ESA lead and other mill employees received training on the use of the steam assessment tools for future evaluation of steam system related projects. Particular attention was paid to the Steam System Assessment Tool (SSAT) and it was used extensively in the course of the assessment to determine project economics once critical projects parameters were determined.

Focus of Assessment:
This assessment focused primarily on Utilities and Environmental (U&E), which includes the boiler house.

Approach for ESA:
The assessment started with a ½ day training activity mill staff to provide a thorough review of the steam tools, particularly SSAT. The Steam System Scoping Tool (SSST) was completed on the second day full day of the assessment with the mill scoring about 81-percent. Scores above 75% are considered very good. This indicates that the mill is doing very well with respect to general steam system management practices.

General Observations of Potential Opportunities:
Below are brief descriptions of each opportunity evaluated. Each opportunity has been rated based on the following definitions:

1. <u>Near term opportunities</u>: Include actions that could be taken as improvements in operating practices, maintenance of equipment or relatively low cost actions or equipment purchases.
2. <u>Medium term opportunities</u>: Require purchase of additional equipment and/or changes in the system such as addition of recuperative air pre-heaters and use of energy to substitute current practices of steam use etc. It would be necessary to carryout further engineering and return on investment analysis.
3. <u>Long term opportunities</u>: Require testing of new technology and confirmation of performance of these technologies under the plant operating conditions with economic justification to meet the corporate investment criteria.

<u>1. Reduce Steam Demand – Consider a Condensing Economizer on Gas Boilers</u>
Condensing heat recovery (CHR) systems are designed to allow boiler exhaust to be cooled to a much lower temperature (90°F to 130°F) than is possible with a "standard" economizer such as the one on the #1 gas boiler. The benefit is that the water vapor present in the exhaust from fuel combustion contains 8 to 10-percent of the fuel energy input to the boiler. This "latent" heat is not available until the vapor begins to condense at approximately 135°F. Standard economizers are not designed to handle corrosive condensate and are limited to exhaust temperatures of 250°F to 325°F depending on the fuel.

Because the effectiveness of a condensing economizer depends greatly on inlet temperature, it is desirable to have the inlet water as cool as possible. To allow an estimate of cost savings potential, water at 60°F and 290-gpm is assumed available. At the #1 boiler stack temperature of approximately 335°F, a direct CHR system will heat the water from 60°F to approximately 135°F. Based on experience at other mills the implementation cost will likely be from $1-million to $2-million. This project is recommended for further consideration.
Notes:

1. Because this project provides hot water, it *may* compete with efforts to increase turbine output with 40-psig steam and heat recovery from the paper mill lift station. As a result, careful consideration should be given.

<u>2. Steam Demand Reduction - Recover Heat from the Paper Mill Lift Station to Filter Plant</u>
During facility discussion, it was noted that the effluent from the paper mill lift station to the wastewater treatment facility is often in the range of 110°F. Recovering heat from this water stream to preheat cool water into the filter plant has three primary advantages:

a. The water temperature can be reduced to approximately 90°F to help meet upcoming regulatory changes.
b. The heat recovered can be used transferred to the filter plant influent to preheat cool water that is presently heated with steam.
c. The non-contact cooling flow will be reduced, lower hydraulic demand of the WWTP.

Using the waste heat to preheat filter plant water must be approached with caution to avoid using warm water in areas where cool water is necessary. An example is vacuum pumps that require cool water for efficiency and good vacuum performance. Additionally, since the mill uses numerous waste heat exchangers to preheat cool water, care must also be taken to account for any offset in savings that would result from preheating water to those units.

Nevertheless, preliminary investigations indicate that there is the potential to reduce steam water heating requirements by as much as 10,000-pph.

Initial cost estimates for the installation of one option are on the order of $605,000.

Notes:
1. A mill water and energy balance is recommended as a first step to this opportunity due to the complexity of the mill water system. This will help avoid simply moving energy around without realizing any economic benefit and the possibility that cool water process/equipment requirements are upset with warm water use.

<u>3. Increase Boiler Efficiency- Use #1 Boiler Economizer to Preheat #2 Boiler Feedwater (Near Term)</u>
Boiler feedwater economizers recover heat from the exhaust to preheat boiler feedwater. The feedwater economizer on boiler #1 preheats feedwater from approximately 268°F to 333°F while reducing the exhaust temperature from 564°F to 336°F (at ~78-kpph steam). This boiler is fired on gas so the minimum acceptable temperature for the leaving exhaust is 250°F, indicating that there is significant room for improvement of heat recovery if there is sufficient load. Since the #2 boiler does not have a feedwater economizer, passing the #2 boiler feedwater to the #1 economizer provides an opportunity for cost effective heat recovery without significant risk to boiler operation.

Preliminary analysis indicates that limiting the #1 boiler exhaust to 250°F will heat the #2 boiler feedwater by approximately 37°F. Due to the relatively simple nature of this opportunity the simple return is estimated at less than 1-year.

This opportunity is recommended for further consideration and implementation as appropriate.

Notes:
1. Interlock controls and valves should be used to provide the isolation of the boiler feedwater line if necessary.
2. The hydraulic capacity of the economizer needs to be verified.

<u>4. Increase Condensate Recovery Rate</u>
Steam condensate at one part of the facility is dumped due to concerns about contamination that could occur in the event of a heat exchanger tube leak, even though the majority of the time there is no contamination. Data obtained during the assessment indicates a loss of 16,000-pph on average, equivalent to a makeup water flow of 32-gpm. Recovering this condensate is equivalent to reducing makeup water requirements by approximately 19-percent.

Assuming that the heat no longer recovered from the acid condensate is used elsewhere, the savings will remain as estimated. However, if this is not addressed the savings will only materialize when the water temperatures are low enough to use all available acid condensate heat.

This option is favorable and is recommended for further investigation.

<u>5. Improve Boiler Efficiency –Implement a Scheduled Seasonal Tuning Program (near term)</u>
Boiler tuning is necessary maintain proper fuel to air ratios across the operating boiler load range. Based on discussions during the assessment the boilers are tuned once per 12 to 18 months. Combustion testing on the #2 boiler indicates that exhaust oxygen levels are approximately 1.5 to 2-percent higher than indicated in the control room. Additionally, levels

of CO increased as firing rates were increased, the opposite of what is expected. This alone indicates that the gas burners are likely in need of adjustment.

It is difficult to accurately estimate the efficiency gain possible from tuning since this is dependent on the burner design and condition as well as controls. However, due to seasonal changes it is recommended that tuning be performed twice per year. If boiler efficiency can be increased by ½-percent on average (not unreasonable) the simple return is approximately 2-months based on present costs for tuning

This opportunity is recommended for further consideration.

<u>6. Improve Boiler Efficiency - Reduce the Boiler Blowdown Rate (Near Term)</u>
The steam boilers include a blow down heat recovery system that is intended to recover heat from the hot blow down prior to loss of flash steam and hot water. While the blowdown exchangers are recovering a significant amount of heat from blowdown, the acid condensate heat recovery exchanger used to preheat the boiler makeup water *before* it is further heated by the blow down heat recovery exchanger is limiting the amount of heat that is removed. As a result, boiler down water is being sent to the flash separator at 165°F. Since the flash separator discharges to the sewer, this represents a lost heat recovery opportunity.

The blowdown set points range from 1,600-µmho to 2,300-µmho depending on the boiler. The feedwater conductivity was tested at approximately 220-µmho while a brief review of boiler water test logs places the "average" boiler water conductivity at approximately 1,800-µmho. A "spot check" placed the blowdown rate at approximately 10.3-percent, consistent with the 10 to 12-percent value typically observed by boiler house staff.

Total dissolved solids (TDS) is related to the buffered conductivity as TDS (ppm) ÷ 0.7. Assuming that the "average" boiler water test log conductivity values are buffered, the estimated TDS of the boiler water is 1,260-ppm (1,800-µmho). According the Babcock & Wilcox ("Steam: Its Generation and Use") the recommended maximum TDS is 2,000 to 2,500-ppm for boilers operating in a range of 600 to 750-psig.

Using a TDS of 2,250-ppm as a guide, it appears that the blow down rate can be reduced from approximately 10.3-percent to an average of 6.8-percent.

This opportunity is recommended for further consideration.

Notes:
1. Work with your water chemistry service provider to ensure there are no limitations to reducing blowdown rate.
2. Verify all estimates related to feedwater and boiler water conductivity.
3. The hand blowdown valve was found to be continuously leaking into the flash separator. This is in the process of being repaired, but represent a loss of saturated hot water at 600-psig directly from the boiler.

<u>7. Recover Hot Air from the Boiler House Roof</u>
The location of the combustion air intake for the boilers and approximate inlet air temperatures based on a "snap shot" measurement and control panel data are as follows:
- #1 boiler: upper level, temperature ~138°F
- #3 boiler: basement, temperature ~75°F
- #7 boiler: ground level, temperature ~80°F

Considering the #2 boiler as an example, the FD fan will add heat of compression so the actual temperature of combustion air to the air preheater will be somewhat higher than ambient. Generally, increasing the combustion air temperature will increase boiler efficiency approximately 1% for each 40°F increase. However, the "effectiveness" of the air preheater that uses exhaust heat to preheat combustion air from the FD fan will decrease, causing some of the savings to be lost. For example, assuming the average combustion air temperature to the boiler #2 FD fan is increased from 80°F to 115°F, the efficiency gain based on the guideline would be:
1%/40°F x (105 – 80) °F = 0.625%

However, the higher *combustion air* temperature to the air preheater will cause the *exhaust leaving* air preheater to increase from approximately 387°F to 400°F, an increase of 13°F so only about 50-percent of the benefit will be realized.

This opportunity is recommended for further investigation.

8. Increase Condensate Recovery Rate – Improve Hotwell Management

Discussions with mill staff indicate that improved condensate management is a good opportunity to increase the condensate recovery rate. An example of one area to improve condensate management is providing better feedback to the control room on hot well operation. The hot well over flows at times although it is unknown how frequently. Because there is no control feedback to the boiler house, the overflow events go undetected unless someone happens to be there when the event occurs.

Another significant advantage of improved control feedback is that the data can be converted into cost savings directly on the control computer screens for the operators to see, as was done in other areas of heat mill. The result is that the operators are aware of dollar savings on a real time basis and the changes necessary to maximize the heat recovery performance as much as possible. Without the real time readout, the operators do not have a true sense of how the energy relates to dollars.

This opportunity is recommended for further consideration.

9. Use 40# Instead of 140# Steam on Wood Room Unit Heaters

This opportunity involves replacement of 140-psig steam provided by a 600-140-psig pressure reducing station with 40-psig directly from the back pressure turbine. The unit heaters are used to provide comfort heating in an area that does not appear to be critical. For this reason, the 10 to 20-percent reduction in heat output resulting from lower temperatures does not appear to be an issue.

This project may require piping size increase to account for the higher specific volume of 40-psig steam and the related pressure drop. However, this does appear to be worth further consideration and implementation as appropriate.

10. Reduce Vented Steam –Hot Lime Softener & DA Tanks

Visual observation of DA tank venting and the hot lime softener vent suggests that there is likely over venting occurring. Both of these vents are for removal of dissolved gases, particularly oxygen. The design guideline vent rate is approximately 1/10 of one percent of the design steam flow (375-kpph), however the actual flow is at approximately 188-kpph (2007) due to a production decrease (paper machine shut down). Using the estimated average steam flow as a guide the vent rate should be approximately 200-pph.

While measurement was not possible, the vent rate was estimated to be approximately 500- based on visual observation. Reducing the vent rate to 200-pph will reduce steam demand by approximately 300-pph. Generally, valve adjustment is sufficient to reduce venting, but replacement may be necessary depending on the orifice diameter (there usually is an orifice drilled into the valve gate).

The simple return will be nearly immediate. This opportunity is recommended for further consideration and implementation as appropriate.

Notes:

1. While visual observation of vent rates can be used as a guide to DA tank performance, changes in the amount of chemical oxygen scavengers should be monitored for indication that the DA tank is still performing as expected. Increases in use of chemical scavengers indicate diminished performance, and the rate should be increased somewhat until the balance is found. This will help minimize the chance for poor oxygen removal and potential boiler damage. Seek assistance from the facility water chemistry service provider.
2. As a general guide, a gap between the vent and plume should be approximately 2 to 3-inches with a plume about 2-feet in height.
3. Consider whether the DA tank pressure can be reduced, as this will lower the water temperature to the #1 boiler economizer and improve waste heat recovery effectiveness.

11. Consider a VFD on Boiler #1 ID Fan

The inlet damper on the boiler #1 ID fan is significantly closed, providing an opportunity to apply a VFD to slow the fan and removing the pressure drop across the damper. Ampere readings on the 350-hp fan motor indicate that the electrical power requirement is approximately 127-hp (95-kW). Based on the #1 boiler average steam flow for 2007 and assuming that a 5-inwc pressure drop across the fan will be sufficient, the estimated electrical power with a VFD is 43-hp.

This project is recommended for further evaluation and implementation as appropriate.

Notes:

1. As with the #3 boiler, flow and duct pressure testing is preferred to provide the best estimate of potential cost savings.

Management Support and Comments:

Generally, management and the attendees appeared to be happy with the results obtained thus far. The models were also well received. Based on the close out meeting, mill staff appeared to be pleased that Mr. Tom Tucker and Mr. Dick Reese were able to focus on both process and steam system opportunities that were not identified in the Pinch Study.